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THE IMPACT OF COSTS ASSOCIATED WITH NEW ENVIRONMENTAL STANDARDS UPON THE PETROLEUM REFINING INDUSTRY

PART THREE

THE IMPACT OF ENVIRONMENTAL CONTROL COSTS

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TABLE OF CONTENTS

INTRODUCTION AND SUMMARY		3
SECTION I.	INDUSTRY COST AND PRICE EFFECTS	6
	A. Timing of Price Increases	7
	B. Effects of Capital Investment on Refinery Costs and Product Prices	9
	C. Effect of Changes in Operating Expenses on Refinery Costs and Product Prices	12
SECTION II.	CONTROL COST DIFFERENCES AMONG REFINERIES	18
	A. Refineries Larger than 25,000 Barrels per Day	20
	B. Small Refineries	21
	C. Temporizing Influence on Small Refiner Vulnerability	27
SECTION III.	EMPLOYMENT AND OTHER RELATED EFFECTS	29
	A. Employment Effects in the Petroleum Refining Industry	30
	B. Other Effects	32

EXHIBITS

1. Air Effluent Quality Control Total Costs
   a) Air Effluent Quality Control Unit Costs - A
   b) Air Effluent Quality Control Unit Costs - B

2. Water Effluent Quality Control Total Costs
   a) Water Effluent Quality Control Unit Costs

TABLE OF CONTENTS
(Cont.)

3. Air Pollution Abatement Control Costs - Petroleum Refining

4. Water Pollution Abatement Costs - Petroleum

INTRODUCTION AND SUMMARY

This is Part Three of a three-part report. It is divided into three sections. Section I deals with cost and price effects of environmental controls on refinery operations in general. Section II shows the differing impacts on various classes of refineries. And Section III assesses employment and other miscellaneous effects.

The cost data used in this study were furnished by the Environmental Protection Agency. They are reproduced in Exhibits 3 and 4, for air and water controls respectively, and are summarized in Exhibits 1 and 2. They do not include the cost of replacing high sulfur liquid refinery fuel with low sulfur oil. Discussion with EPA led to the use of a cost differential of 90 cents per barrel between low and high sulfur liquid refinery fuel.[1)]

On the basis of the cost data furnished, we present the following conclusions:

(1) We estimate oil product price increases of about 8 cents per barrel (42 U.S. gallons), i.e., under 0.2 cents per gallon, or an increase of about 1 2/3 percent will occur. This amount consists of three components: 5 3/4 cents to replace high with low sulfur refinery fuel, 1 3/4 cents to defray the costs of control equipment to be installed in new facilities, and less than 1/2 cent for operating costs of the control equipment. Only about one quarter of the price increase results from the requirement to install and operate new equipment. Therefore our estimate of the price increase is insensitive to the uncertainty in the EPA's cost estimates. But our conclusions are very sensitive to the assumed additional costs to be incurred as a result of the substitution of low for high sulfur liquid refinery fuel.

1) This number is not directly comparable to the other cost data furnished us because the 90 cents includes both a capital and an operating cost element. Also, although 90 cents probably is a reasonable long term estimate, it is far below the current differential. This is discussed in Part One, The Executive Summary.

(2) The industry's cost for installing control equipment in new facilities will be about $113 million. This amount will be fully recovered through increased product prices.

(3) New control equipment in existing refineries has a higher cost per barrel of capacity than control equipment installed during new refinery construction or major expansion. This difference results in an investment which is non-recoverable, about $128 million out of a total capital requirement to conform old facilities of approximately $732 million. On the other hand there will be an increase in industry cash earnings of about $86 million per year as a result of and at the time of the substitution of low for high sulfur oils used as refinery fuels.

(4) The industry will recover a substantial part of its control investment through increased product prices. This is possible because demand for the industry's products is increasing and because the bulk of them have no currently economic substitutes. Nor are they subject to significant foreign competition. Also, the price elasticity of demand for most of the industry's products is small. Hence the minor price increases which will take place will not cause a diminution in the industry's growth rate.

We do not think it likely that, except in minor instances, crude oil producers will absorb any of the increased refining costs in the form of lower prices for crude petroleum.

(5) Refineries will be affected differently by the new standards depending on their current effluent control facilities, their size and the oil refining processes installed. A refinery which already conforms to new standards obviously will be unaffected by their imposition. Refineries above about 25,000 barrels per day crude oil distilling capacity have going concern values so far above the estimated costs of meeting new standards that they will certainly install whatever effluent control facilities are needed to permit continued operation.

(6) Refineries below about 25,000 barrels per day capacity, and especially those below about 10,000 barrels capacity, face control costs quite large relative to their going concern value. Some of them face capital requirements for control equipment of $200 per daily barrel of capacity compared to apparent values of below $500. It is possible that perhaps a dozen, accounting for less than 1 percent of industry capacity, may be unable to finance control facilities. Their combined employment is estimated at below 1,000 people out of a total industry employment of about 150,000.

SECTION I

INDUSTRY COST AND PRICE EFFECTS

In order to discuss the effect of control costs on industry prices we must first summarize the discussion in Part Two of this study about competition from other industries and from foreign sources as well as our evaluation of the extent of competition between refiners.

The products of this industry are subject to very little competition from products of other industries except for the competition of natural gas and coal. But since the supplies of gas are limited and environmental factors are unlikely to increase the competitive pressure of coal it seems reasonable to assume that domestic competition will not limit price increases brought on by increased environmental control costs in the refining industry.

Also, since imports of oil products, except for residual fuel oil, are limited by a quota system, foreign competition will not inhibit price increases. Because residual makes up only about 4 percent of the refinery gate value of the industry's products we shall, in this section, neglect competition offered by foreign resid on the value of refinery products.

Consequently we believe that the price elasticity of demand for the industry's products is low, especially because the principal competing products are either limited in supply or also affected by environmental costs.

In Part Two we showed that refiners' marginal costs closely approximate refinery gate prices. In other words the price elasticity of demand facing individual firms is high.

A. Timing of Price Increases

The costs of operating refineries in conformance with new environmental standards are of three types: Capital investments, increased fixed operating costs, and increased operating costs

which vary with output. Only the third type of added costs, i.e., those which vary with output, can be passed on in the form of price increases as they are incurred.

The most influential of the costs of conforming to new standards are of this type. The requirement to use desulfurized liquid fuel in lieu of currently used liquids will raise the industry's marginal cost. We expect that this increase in marginal cost will result in price increases when incurred. This will be further discussed in C below.

Recovery of the first two types of added costs requires that the industry be expanding. With demand for the industry's products increasing, the market provides financial incentives to attract the capital needed for expansion. That is, the industry price structure must provide incentive to attract new capital.

As demand increases, output from existing facilities increases. So do marginal costs[1] and hence, prices. At some point it becomes less costly to build new facilities,[2] including required environmental control equipment, than to increase output further in existing facilities. The added costs resulting from new environmental control equipment are at this point included in prices.

When new facilities are built not only the prices of product made in new plants but of all products will reflect the added costs. This is because it is impossible to distinguish product (gasoline, turbine fuel, etc.) made in "new" plants from that made in "old"

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1) Marginal costs increase principally because a refinery's yield structure deteriorates as output increases. In any existing plant the fraction of high valued products per barrel of crude declines as output approaches capacity.

2) There have been few new plants built. In recent years the bulk of industry expansion has been in the form of "debottlenecking" of existing refineries.

plants. At this time the added control costs will begin to be recovered on all products. The extent of the recovery will depend on the difference in control costs per unit of output in "new" versus "old" facilities and the time lag between the installation of control facilities in "old" plants and the construction of "new" ones.

Some control equipment can be installed more economically in new than in old facilities. Consequently, the recovery of control equipment costs in existing plants is likely to be less than complete. (This is further discussed in B and C below.)

It is possible that the recovery will begin slowly because there is currently some unused refinery capacity. Therefore the industry is unlikely to build facilities which would significantly add to output before 1973 or 1974. Recovery on investments made before then is likely to be delayed.

B. Effects of Capital Investment on Refinery Costs and Product Prices

Except for the cost of using desulfurized fuel, practically all costs of pollution abatement, both air and water, are fixed costs. Substantial amounts of capital will be required to install the equipment needed to meet new environmental standards. EPA estimates a required capital investment of about $845 million in the next 5 years. On the basis of these investment figures we shall estimate the impact on refinery costs and, therefore, on product prices.

The capital investment requirements for the period 1972 through 1976 shown in Exhibits 1 and 2 are restated below.

Capital Investment in Million Dollars

	Air(1)	Water(2)	Total(3)
1971	43.9	54.3	98.2
1973	66.7	55.4	122.1
1974	181.0	56.6	237.6
1975	203.8	57.7	261.5
1976	66.7	58.8	125.5
Total	562.1	282.8	844.9

(1) Plus or minus 25%. See Exhibit 1

(2) Plus 60% or minus 25%. See Exhibit 2

(3) Plus about 35% or minus 25%.

Of the total capital estimate only a relatively small fraction ($113 million) is required to conform refining facilities that will be built in the next 5 years.

Since only this fraction of the capital can reasonably be expected to affect prices we shall examine its relationship to the volume of new products to be produced. Rather than show it in annual increments we will examine it in terms of the total capital and total new output in the period 1972 through 1976.

Estimated Capital Costs To Control New Facilities
1972 - 1976 (Million $)

	Low Limit	Expected	High Limit
Air	78.75	105.00	131.25
Water	5.88	7.84	12.54
Total	84.63	112.84	143.79

At an annual industry growth rate of about 3.5%,[1] refinery capacity will increase by about 2.5 million barrels per day during the period 1972 to 1976. Based on the above capital requirement for effluent control of $113 million, this is about $46 per daily barrel of new refinery capacity.

The price increase to be expected from the requirement to spend the additional capital of $46 per daily barrel of new capacity is about 1 3/4 cents per new barrel[2] manufactured. 1 3/4 cents per barrel is under 1/2 percent of average refinery gate costs. [If the upper limit of capital costs is used the estimated price increase becomes about 2 1/4 cents per barrel which also is less than 1/2 percent.]

A long term price increase of 1 3/4 cents per barrel of refined product sold is expected to compensate refiners for the costs of installing new control equipment along with new refinery investments. The following calculations indicate that this price increase will be inadequate to compensate refiners who must install equipment in existing plants. Capital requirement for this latter purpose for the period 1972-1976 was estimated by EPA to be about:

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1) The capital requirement estimated by EPA is based on a growth rate of 2.7 percent and is adjusted for increases in water use productivity. Our use of 3.5 percent results in a small underestimate of per barrel capital required, hence an underestimate of the probable price increase and also an overestimate of the portion of capital that will not be recovered. The "error" is within the range discussed on this page.

2) A revenue of 1 3/4 cents per barrel per day is about $6.30 per year. Approximately this amount is required to return 8 percent after taxes on a capital investment of $46 per barrel per day. With one exception, an 8 percent cost of capital is used throughout our analysis.

Estimated Capital Costs to Control Existing Facilities (Million $)

	Low Estimate	Expected	High Estimate
Air	342.82	457.10	571.37
Water	206.07	274.76	439.61
Total	548.89	731.86	1,010.98

At an industry capacity of about 13.1 million barrels per day in 1972, the capital required to conform existing facilities is about $56 per daily barrel of capacity (low estimate $42; high estimate $77). This $56 compares to about $46 per daily barrel cost of expansion capacity and indicates that it costs more to conform existing than new facilities to environmental standards. Further, the 1 3/4 cents per barrel sold price increase will pay for only a $46 investment per daily barrel of capacity. The differential amount of $10 per daily barrel of capacity not covered by a price increase represents about $128 million. This $128 million of capital (the uncertainty associated with this number is high) must be viewed as a one-time "tax" on the refining business which cannot be expected to be recovered. An offsetting effect on income resulting from substituting low sulfur for high sulfur fuel is discussed below.

C. Effect of Changes in Operating Expenses on Refinery Costs and Product Prices

Changes in operating expenses caused by environmental standards are of two kinds: 1) Costs associated with operating and maintaining new control equipment and with more precise monitoring of refining processes, and 2) cost of more expensive low sulfur refinery fuel.

1. Cost of operating new control equipment

Except for the cost of using desulfurized fuel practically all costs of water and air pollution abatement are fixed and do not vary with the level of output.

Nevertheless, in order not to minimize the effect of such costs on prices in the short run we shall assume that all of the operating and maintenance costs shown in Exhibits 1 and 2 are in fact variable with respect to output and that they increase in direct proportion to refinery runs.

The estimated pollution control operating and maintenance costs, in millions of dollars per year are:

	1972	1973	1974	1975	1976
Air[1)]	.70	2.10	6.90	12.30	13.70
Water[2)]	1.43	2.87	4.36	5.75	7.18
Total	2.13	4.97	11.26	28.05	20.88

Projected refinery throughputs increase from roughly 4.3 billion barrels in 1972 to 4.9 billion in 1976.[3)] Thus, for the years 1972 to 1976 the approximate average unit operating and maintenance costs for water and air combined, but excluding the cost of using low sulfur liquid fuel, are: (See next page)

1) Subject to a variability of -25% to +25%. See Exhibit 1

2) Subject to a variability of -25% to +60%. See Exhibit 2

3) 1970 total inputs were about 4 billion barrels and we assume a growth rate of 3.5% (1970 data from U.S. Petroleum Industry Statistics, 1956-1970 American Petroleum Institute, April 1971, p. 18.

Average Cost of Operating and Maintaining Control Facilities

	Estimated O & M Cost ($ million)	Estimated Throughput (billion bbls.)	Average Cost (Cents Per Barrel)
1972	2.13	4.3	0.05
1973	4.97	4.4	0.11
1974	11.26	4.6	0.24
1975	18.05	4.7	0.38
1976	20.88	4.9	0.43

The unit costs rise from 0.05 cents to about 0.4 cents per barrel from 1972 to 1976. Even if these costs are underestimated by as much as one half, they are extremely small. And even if considerable variation among plants exists, these costs cannot account for differences in the ability of firms to compete effectively. We use a 1/2 cent/barrel price increase estimate.

2. Cost of substituting low sulfur for high sulfur refinery fuel

A significant component (10 percent) of the fuel burned in refineries is residual fuel oil. Most of this oil has a sulfur content ranging from 1 to 4 percent. It is also the highest cost fuel burned by the industry so it is the fuel that enters into the determination of marginal costs. Air quality standards proposed for fuel-using industries will require them to reduce their emmissions of sulfur oxide due to combustion of high sulfur fuels, either by removing sulfur oxides from stack gases or by substituting low sulfur fuels. This requirement will undoubtedly also be imposed on refineries.

At this time there is no full scale equipment operating for removing sulfur oxides from stack gases in the United States. Removal of sulfur from refinery fuels is therefore the alternative we shall consider.

A requirement to burn low sulfur liquid fuel in refinery boilers and furnaces would significantly increase refinery costs. On the basis of the cost difference estimated by EPA of 90 cents per barrel between current liquid fuel and low sulfur liquid fuel we estimate the increase in the marginal cost of refining as follows:

Approximately 700,000 BTU of energy, equivalent to about 12 percent of crude intake, are used to refine a barrel of crude oil.[1] Of this 12 percent about half is nonsalable refinery by-products (gas and catalytic coke) which are consumed as fuel in refinery operations. Neglecting processing gains this leaves 94 percent (100% minus 6%) salable product and an additional fuel requirement of 6 percent (12% minus 6%).

The additional fuel may be acquired by outside purchase or by using products which would otherwise be sold. In either case the material consumed is, on the margin, largely residual fuel oil. If this fuel's cost rises by about 90 cents per barrel to reflect the cost of desulfurizing, then marginal refining costs will rise by about 5 3/4 cents per barrel[2] or 1/7 cent per gallon. We expect that when marginal refinery fuel is required to be desulfurized this cost increase will be passed on to consumers in higher product prices.

Because only a part of the refining industry's total fuel requirements will be affected by this cost increase[3] the

1) Mineral Industry Survey - Petroleum, Bureau of Mines, February, 1971, Table 23.

2) 6% fuel basis crude ÷ 94% product basis crude x 90 cents per barrel fuel = 5.7 cents per barrel product.

3) Refinery fuel costs may increase for reasons unrelated to environmental considerations. (See next page)

revenue implications require explanation. In addition to fuel oil, coal, purchased electricity and purchased steam presumably also will rise in cost because they will be subject to low sulfur standards. We estimate that by 1976 these energy sources together will account for about 730 trillion BTU of energy, equivalent of 120 million barrels of fuel oil per year.[1] Since the cost (or value) of fuel oil is expected by the EPA to rise by 90 cents per barrel due to the costs of desulfurizing, the refining industry will incur a fuel cost increase of about $108 million per year by 1976. The marginal cost increase of 5 3/4 cents per barrel applied to the affected "barrels" implies an average cost increase of about 2 1/4 cents per barrel.

Since we expect prices to rise by the increase in marginal costs (5 3/4 cents per barrel) the annual gross revenue of the industry will increase by about $280 million (4.9 billion barrels of product outturn x 5 3/4 cents per barrel). Net increase in cash income before taxes is $172 million per year ($280 revenue increase minus $108 million increased costs of liquid refinery fuel). And the after tax cash income effect is half of this amount, or $86 million per year. This estimate is significantly affected by the cost differential between currently used liquid

1) We assume that the volume of natural gas consumed in refineries in 1976 will be the same as in 1970. So other forms of purchased energy will be required to supply all of the net increase in energy needs. Also, we assume that net additional fuel required per barrel holds constant at 6 percent.

refinery fuel and the higher cost fuel which will be used as a result of environmental regulations. Hence the uncertainty associated with the $86 million estimate is high.[1)]

The current price differential between high sulfur and low sulfur (maximum 0.6 percent) oil is about twice as high as that used here. For 0.3 percent sulfur oil, the maximum permitted in some places, the differential is still greater.[2)] The differential is the result of a scarcity of this material because enough facilities for its manufacture have not yet been installed. A very rapid expansion of the requirements to burn only low sulfur oil may prevent the price differential from falling to the economic long term level estimated by EPA for several years. In that case, the prices of oil products will be higher than estimated here and the costs of other energy using industries will also be affected.

1) A diminution in the availability of natural gas or an increase in price, both of which may occur for reasons unrelated to matters studied in this report, would increase refinery costs. But these cost increases, because they are not related to environmental matters, are irrelevant to the cost and revenue implications discussed here unless gas prices increase sufficiently so that gas replaces low sulfur liquid as marginal refinery fuel.

2) At present, October, 1971, cargo price US Gulf of residual is
High sulfur $2.00/barrel.
Maximum 0.6 percent sulfur
$3.70 - $3.80/barrel
Platt's Oilgram Price Service, October 28, 1971.

SECTION II

CONTROL COST DIFFERENCES AMONG REFINERIES

Almost every refinery in the United States will have to install some facilities to conform to new environmental standards. In this section we will classify refineries by the kind and amount of environmental control equipment they will need. And we will assess the probable impact of control costs on the economic viability of each class. We will not consider the effects of possible regulations requiring a shift to low sulfur refinery liquid fuel.

We will look at the refinery population in two groups, those with crude oil distilling capacity greater than 25,000 barrels per day and those of lower capacity.

From the Environmental Protection Agency control cost estimates we have interpolated the cost of installing a full complement of air and water pollution control facilities for a hypothetical 25,000 barrel per day fuels refinery. This is about a median size refinery. The estimated cost is about 3 and 2/3 million dollars (2.41 million for air and $1.25 million for water). Converting this capital to a unit cost basis (at 8 percent after tax cost of capital) and adding operating expenses brings the control cost for this refinery to 8 cents per barrel.

In Section I we estimated that industry average refined product prices would increase about 8 cents per barrel, of which the increased costs of low sulfur oil for refinery fuel would take on the average about 2 1/4 cents (see page 16) leaving about 5 3/4 cents before operating expenses and capital charges for the industry as a whole.[1] This is less than the 8 cents per barrel (see previous paragraph) which a 25,000 barrel refinery would incur to control its facilities. However the difference is smaller than the per barrel income of this size refinery. Thus a median sized refinery needing to install a full complement of environmental control equipment would suffer a long-term competitive disadvantage, relative to a large plant, but by an amount which is too little to cause it to cease operations.

1) Note the 5 3/4 is 8 minus 2 1/4. It is not the 5 3/4 derived on p. 15.

A. Refineries Larger Than 25,000 Barrels Per Day

In our calculation above we found that a hypothetical refinery of 25,000 barrels per day capacity can, without question, continue to operate profitably in compliance with new standards. For several reasons the larger the refinery, other things being equal, the greater its cost advantage.

First the economics of scale favor larger installations. The EPA estimates that a completely new plant to treat 10 million gallons per day of water would cost only 19 times as much as one to treat 0.1 million gallons per day (one hundredth as much). This is an exponential scale factor of about 0.65 which is typical of oil processing units too. The same scale factor applies to controlling particulate and carbon monoxide emissions from catalytic crackers.

Further, because of the larger absolute amounts involved it is profitable for larger refineries to install relatively more equipment to recover heat used in the refining process. Since much of the water consumed by a refinery is used for cooling, the more heat recovered the less water used (though heat may also be rejected to air). There is an offsetting effect in that smaller refineries in general produce a lower fraction of processing-intensive products (gasoline and lubricating oil) and therefore use less heat per unit processed.

Again, because of the absolute magnitudes involved, it is profitable for a larger plant to conserve relatively more water.

Finally, larger refineries are probably closer to full compliance with environmental standards than smaller ones. There are several reasons for this. The pollutants discharged from a large refinery may have been sufficient to have required control in the

past. Also, larger refineries are more clustered than small ones. This amplifies the effects of pollutants and the pressure to eliminate them. Some small refineries, on the other hand, are in rather isolated areas where environmental problems in the past may not have been of high concern.

We conclude that on the basis of their size, refineries with a crude oil distilling capacity of 25,000 barrels per day or more should encounter no difficulty in operating profitably due to new control costs. We shall therefore give our attention hereafter to the smaller plants.

B. Small Refineries

Half the refineries in the United States (127) have a throughput capacity of less than 25,000 barrels per day. They account for only about 8 percent of industry capacity (see Exhibit 9 of Part Two).

In Part Two, Section II A.1, we categorized plants as follows because they use certain processes which in turn determine effluent control requirements:[1)]

Refining Processes Installed				Effluent Control Required		
				Air		Water
Large Cat. Cr.	Thermal or Small Cat. Cr.	Hydro Processes	Lube Mfg.	H_2S	CO & Cat.	BOD
X				X	X	X
	X			X		X
		X		X		
			X			X

1) In addition to the listed facilities, every refinery will need to have floating roofs on its large gasoline and crude oil storage tanks and also a water effluent treating plant to neutralize and remove oil and suspended solids from waste water.

We note again that all the following discussion is limited to refineries with less than 25,000 barrels per day crude capacity, which account for 8 percent of industry capacity. We also make the conservative, and unrealistic, assumption that none of these plants has, at present, any of the effluent controls which will be required. Because of the different control technology required the impact of new environmental standards will be different on each class of small refineries.

1. Refineries with catalytic crackers of above 10,000 barrels per day capacity.

There are only two refineries in this class of which the smaller has a crude oil capacity of about 22,000 barrels per day.[1)] Since 22,000 barrels per day is so close to 25,000 that the control costs would be little different, we conclude that refineries in this category are as viable as those of 25,000 barrel capacity.

2. Small refineries requiring sulfur and BOD removal facilities.

There are forty-one such refineries in the United States[1)] with an average crude capacity of 12,500 barrels per day. If we assume a waste water flow rate of one barrel per barrel of crude processed, we can estimate the pollution capital costs faced by these plants[2)] (capital cost assumed 8 percent per year after tax):

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1) Oil and Gas Journal, March 22, 1971, p. 98 ff.

2) Calculated from the EPA estimates as summarized in Exhibits 1 and 2. The EPA estimates imply an exponential scale factor of 0.7 for air effluent facilities and of 0.57 for water facilities.

Costs of Controlling BOD, H_2S and Tanks

Crude Capacity, Thousand Barrels Per Day	Effluent Control Capital Costs Million $ Air	Water	Total	Total Capital $ Per Barrel	Effluent Control Unit Costs, Cents Per Barrel, Capital, Operating, and Maintenance
25	1.74	1.25	2.99	120	7
15	1.22	0.91	2.13	140	8
10	0.91	0.72	1.63	160	9
5	0.57	0.48	1.05	210	11

The effluent control costs of 7 to 11 or more cents per barrel are higher than those faced by other refineries But these plants manufacture roughly an industry average yield of products. So they will also receive the price increases estimated above for the industry. Therefore their higher unit control costs (between 2 and 5 cents per barrel) are considered low enough not to cause a plant to close.

For the smallest plants in this group the capital requirement of upwards of $150 per barrel may present a problem. This is hard for us to assess because no published profitability data are available for these plants. We do know that none have recently been built, that 5 have been shut down and a few expanded in five years. Hence we conclude that their average going concern value is greater than zero but less than replacement cost, probably in the range of $300 - $700 per daily barrel of crude capacity.[1)]

1) The lack of published financial information prevents quantitative determinations of the going concern values of various plants. But limits can be calculated. At the high end a new refinery with a yield of products of above average value can be built for $1400 per daily barrel (Oil Daily, October 12, 1971). Near the low end would be a plant in either of PAD Districts 1 through 4 whose income from product sales just balanced its raw material and operating costs, i.e., its operations are breakeven. If such a plant has a crude intake of 10,000 barrels per day or less it qualifies for an import quota of 19.5 percent of crude intake. Quota "tickets" have typically been worth about $1 per barrel (but varying between about $.50 and $1.50 and subject to the risk of the import control program being changed). Capitalizing 19½ cents per barrel at a 12 percent (to reflect high risk) after tax return yields $350 per daily barrel ($.195 x 365 days x 5.0 capitalization factor) as a reasonable minimum going concern value estimate.

Lacking further information, we suggest that possibly 10 of the smaller plants in this group might face shutdowns. However, we later discuss factors which would act significantly to reduce this estimate.

3. Refineries requiring sulfur and oil removal facilities

There are 22 such refineries, with an average 7,000 barrels per day crude capacity. The EPA data given to us do not segregate costs of effluent water treatment into (1) oil and suspended solids removal plus neutralization and (2) BOD removal. We therefore assume that unit water treating costs for these nil BOD plants are half those shown by the EPA. On this basis, air and water effluent control capital costs for a 5,000 barrel per day plant would total about $160 per daily barrel. (On a unit basis, costs for operation, maintenance and capital at 8 percent would total 8 1/2 cents per barrel.)

The plants in this group have a yield structure valued below industry average, and therefore a lower per barrel going concern value. Hence, although compliance costs are about the same as those in the preceding category, their impact may be more severe. In the absence of mitigating circumstances we guess that 5 to 10 of these plants may elect to shut down rather than invest the required capital.

4. Small refineries with lubricating oil manufacturing facilities (but no cracking or hydroprocessing).

There are about seven such plants with an average capacity of 3,200 barrels per day. (Of course, most lube oil is made in large refineries which also make a full range of fuels.)

Lube oil manufacturing facilities are complex and expensive. A refinery primarily dedicated to lube oil manufacture would cost over $1,000 per barrel to build. Even unblended lube oils ("stock" oils) sell for twice the price or more of gasoline.

Lube oil refineries use more water than other refineries[1] because both steam and cooling water needs are high in lube oil processing. But the only air effluent control these plants will need will be floating roofs on tanks. Assuming two barrels of BOD-containing water per barrel of crude, the total capital cost for effluent control facilities in a 5,000 per day lube refinery would be $3/4 million, or $145 per daily barrel. (Operating, maintenance and capital at 8 percent would total 9 cents per barrel.)

We have not previously discussed the economics of lube oil refineries. They are similar to the industry in that control operations will not add to marginal costs. But lube oil marginal costs and prices do not necessarily approach each other as closely as in the case of fuels. Consequently, we are unable to quantitatively assess the short-term price effects of requiring lube oil refineries to install effluent control facilities.

Because the lube oil market is expanding slowly (3 percent per year) prices in the long run will move up by roughly the 9 cents per barrel (1/4 cent per gallon) control costs estimated above. But the recovery of investments in pollution control equipment may be delayed.

Nevertheless, we conclude that all well-maintained lube oil refineries will install effluent treating facilities rather than close down.

5. Refineries with no cracking, hydroprocessing or lube oil facilities (including refineries manufacturing asphalt).

There are about fifty-five of these plants. They have an average crude capacity of about 6,500 barrels per day. Included

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1) Nelson, W.L., Guide to Refinery Operating Costs, 2nd Edition, p. 156.

are about 25 asphalt plants with an average capacity of 7,700 barrels. Since these plants produce neither sulfur oxides nor BOD, their pollution control facilities will be limited to the minimum configuration of oil removal and neutralization of water plus a few floating roofs on tanks.[1] For a 5,000 barrel per day plant total effluent control capital would be about $50 per barrel.

The going-concern value of these plants is probably near their replacement value. A few new ones have been built in recent years and some have been expanded. On the other hand, some of them may have survived solely because of the value of their import "tickets". Some have shut down.

The well located asphalt plants in this group should be able to afford pollution control expenditures. Their floating roof requirements will be very low and the small plants under discussion here tend to have a strong position in their local market. Of the thirty plants that do not make asphalt we guess that fewer than ten could be expected to shut down.

5. Once-through water users

There may be a few refineries in the U.S. not covered above which use water on a once-through basis. Their water use is about 40 times as large as that of typical refineries. These plants, if any, are likely to be located on seacoasts or large polluted rivers. Their water effluent treatment costs will be far larger than those of typical refineries. We do not know how many there are. But it must be only a very few because the Census of Manufacturers data on which the EPA estimates are based show an industry average water flow of 1.3 barrels per barrel crude.

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1) Some asphalt is subjected to air-blowing at elevated temperature to improve its properties. This process can cause serious odor problems. The costs to solve any such problem lie outside the scope of this study.

If only 1 percent (120,000 barrels per day) of total industry capacity used 40 barrels of water per barrel of oil, it would be enough to increase the industry average from 1.0 to 1.3.

C. Temporizing Influences on Small Refinery Vulnerability

In the last several pages we have been assessing the economic value and competitive strength of six classes of refineries. Based on a balance between their apparent worth and the EPA estimated cost to conform their operation to new standards, we guessed that perhaps twenty-five of them would be unable to afford to meet the new standards and would shut down. However, there are several factors not previously discussed that should combine to hold the actual number shut down to half or less of this estimate.

a) Reasonable modifications to the assumed standards could help small refineries considerably. For example, waiving the assumed requirement for duplicate sulfur oxide control facilities would nearly halve their air control costs. Such a waiver would decontrol less than 0.6 percent of total industry sulfur oxides pollution potential.[1)]

b) Some plants will be able to have their water treated at lower-than-assumed costs in municipal treating plants or in facilities shared with other firms.

c) Many small refineries have been built to serve local markets which would otherwise face high transportation costs. This is typically true of plants manufacturing asphalt and military jet fuel. Thus their products can sell at higher prices than products of refineries located in product-exporting areas.

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1) 65 refineries at 11,000 average capacity = 715,000 barrels per day, about 6 percent of industry capacity. But a single sulfur recovery plant would operate, say 90 percent of the time. Hence 0.6 percent decontrol.

d) We have assumed that very small refineries will have to install a complete complement of effluent treating facilities. On the other hand in estimating the industry's costs EPA assumed that 2/3 of the water as well as some of the air effluent treating facilities are already in place. The latter assumption implies that many small refiners have installed some of the needed facilities. Therefore we probably overestimated the costs they will incur.

Most of these apparent offsetting strengths cannot be confirmed without detailed information. But we guess that many of the 25 plants that we think may be unable to afford effluent control facilities are, in fact, financially stronger than they appear to us on the basis of their reported processing facilities. Hence, if control costs turn out to lie near the mean level estimated by EPA, we estimate that perhaps only a dozen small refineries would close, with a total capacity of roughly 100,000 barrels per day and a total employment of perhaps 1,000 (both values are about 0.7 percent of industry total).

Of course, if actual installed costs of control equipment lie near the upper end of the EPA-estimated range, plant mortality could indeed approach twenty-five (200,000 barrels per day capacity and nearly 2,000 employees). In this regard water control costs appear to be more important to small refineries than air control costs because: 1) only a minority of small refineries will need to install sulfur recovery facilities; 2) every refinery will have to have a water treating facility; and 3) the EPA has estimated a much higher upper cost uncertainty for water control (+60%) than for air (+25%).

We think that only two or three plants that would shut down at EPA mean cost level would be saved if actual costs proved to be at the lower uncertainty bound (-25% for both air and water).

SECTION III

EMPLOYMENT AND OTHER RELATED EFFECTS OF ENVIRONMENTAL CONTROL STANDARDS

A. Employment Effects in the Petroleum Refining Industry

1. Unemployment resulting from new standards

In Section II of this Part we estimated that a few small refineries, employing possibly 1,000 people out of a total industry employment of 150,000, might find the cost of meeting effluent quality standards prohibitive.

The few plants that may be closed because of inability to finance pollution control facilities are very small. They are likely to be in areas where the possibilities for profitable expansion have been limited because there has been neither an expanding supply of raw materials nor an expanding market. We would expect most of the shut-down plants to be within a band running from the Louisiana/Arkansas border through Oklahoma, Kansas and Wyoming into Montana. Also they will probably be situated near smaller communities where alternate employment opportunities may be poor.

In Part Two we surveyed the transferability of skills of industry employees. Perhaps one-third of the employees displaced will be able to use their skills only in other refineries or in the process industries. The remaining two-thirds are employable in other industries at their present skill levels if job opportunities exist for them.

2. Re-employment opportunities

a) <u>In existing refineries</u>

Re-employment in other refineries will probably be very limited. For one thing, despite substantial growth in refinery capacity (17 percent between 1964 and 1970), total

refinery employment increased only about 2 percent, from 150,000 to 153,000.[1] It is likely that the bulk of the net employment increases have taken place in very large refineries, those over 100,000 or even 200,000 barrels per day capacity, because plants of this size have accounted for almost the entire net growth in industry output. We expect future industry growth to continue to be in large part via the expansion of existing refineries. These expanding plants are probably not near the small plants which may be forced to close. Hence they are unlikely to offer re-employment opportunities to the unemployed workers of the shut-down plants unless the workers are willing to relocate.

There may be a slight rise in refinery employment due to installation and monitoring of control equipment. But, again, these jobs are not likely to become available in the geographic area where small refineries have had to shut down because of environmental controls.

b) In new refineries

It is most unlikely that the new environmental standards for refinery operation will significantly affect the industry's rate of growth. So new refinery construction will continue at least at the same rate as in recent history. Fifteen new refineries were built in the five-year period 1966-1970, four of them in California and five in Louisiana. California construction reflects that state's role as the largest, and rapidly growing, petroleum product market in the nation. In Louisiana the volume of crude production is increasing and its quality is high. The other six new refineries are all small (200 to 18,000 barrels per day) and serve local markets.

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1) Statistical Abstract of the U.S., Bureau of the Census, Dept. of Commerce, p. 221.

We estimate that new refinery locations will continue to reflect above average market growth or increased raw material availability. An existing refinery located in such a situation would not close and conversely new refineries are highly unlikely to be built in the vicinity of plants that shut down because they cannot afford to install environmental control facilities.

For the long term, increasing amounts of crude oil will be imported from abroad. Canadian supplies will also increase. The most probable locations therefore for new refinery construction are on the East and West Coasts and in the North Central states near major population centers. In these areas there are unlikely to be refineries shut down solely due to the cost of meeting environmental standards in their operations. For these reasons we believe that re-employment in newly built plants will require re-location.

B. Other Effects

1. Unemployment in related industries

Because the total output of the refining industry will not decline due to closing of a few small refineries we foresee no unemployment among either the customer or supplier industries.

As was mentioned, it is possible that the very few and rather small refineries that may close may be in smaller communities. If this should happen there may be some adverse employment effects in these communities. Thus if a small refinery employing, say, about fifty persons, closes, there may be additional unemployment in the local community, especially if some of the displaced workers relocate. It is rather likely that at least the skilled and specialized-to-the-industry workers will relocate in order to

secure employment in their industry. Consequently a small amount of secondary unemployment is a possibility if refineries do close.

2. Effects on related industries

We doubt that the increased costs of refinery operation will significantly affect either customers or crude oil suppliers. The effect on costs is too small and the availability of substitutes for the products of refineries too limited to cause a significant displacement or substitution of competitive products. Cost increases will be passed forward to customers rather than backward to suppliers. If the cost differential of low over high sulfur residual oil remains at the current level instead of dropping to the level assumed in this study, industry prices will be significantly higher and consequently some customer dislocations may be expected. This is discussed in Part One, Executive Summary.

The suppliers of environmental control equipment, such as suppliers of water treating facilities, sulfur recovery plants and electrostatic dust precipitators, will benefit from additional sales.

3. Effects on balance of payments

The extra energy required to operate refineries in conformance with new environmental standards will be about balanced by energy generated by the processes involved. But significant additional use of energy could arise from the need to desulfurize refinery liquid fuels: about three-fourths of refinery fuel used at present is gas, either purchased or own produced. The other one-fourth will require desulfurization in processes that consume fuel equivalent to about one-tenth of their intake. Hence refinery fuel consumption will increase by about one-fortieth ($2\frac{1}{2}$ percent).

U.S. refineries currently consume the equivalent of 1,200,000 barrels per day of liquid fuel. Hence the additional fuel consumed will be about 30,000 barrels per day. This additional consumption would presumably be supplied by imports.[1] At current foreign prices plus freight $40 million per year of foreign exchange would be required.[2]

4. Effects on investment and capital markets

The installation of equipment needed to meet new environmental standards in refinery operations will require about $1 billion of capital. This capital will be added to about $20 billion of capital required by the oil refining industry to finance replacement and growth in the next decade and for facilities needed to meet product quality (low/no lead gasoline and low sulfur fuel oil) requirements. (See Exhibit 16, Part Two) Since it is a small fraction of the total requirement we believe that the demands for capital to meet refinery operating standards will not have a significant impact on the investment or capital markets as a whole.

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1) This assertion is arguable. If U.S. crude oil prices rise more crude will be found and produced. The extent of this relationship is not here investigated.

2) We assume the landed cost of foreign oil to be $ 3½ per barrel. This, times 30,000 barrels per day 365 days per year totals to about $40 million.

Exhibit 1.

AIR EFFLUENT QUALITY CONTROL TOTAL COSTS

Total Industry Capital Investments Required
Million $

	1972	1973	1974	1975	1976	Total
To control emissions from existing facilities	22.9	45.7	160.0	182.8	45.7	457.1
To include control equipment in newly built facilities	21.0	21.0	21.0	21.0	21.0	105.0
Total	43.9	66.7	181.0	203.8	66.7	562.1
Estimated Range						
High limit (+25%)	54.9	83.4	226.2	254.8	83.4	702.7
Low limit (-25%)	32.9	50.0	135.6	152.8	50.0	421.3

Annual Costs to Operate and Maintain Control Equipment
Million $

	1972	1973	1974	1975	1976
Expected Cost	0.7	2.1	6.9	12.3	13.7
Estimated Range					
High limit (+25%)	0.9	2.6	8.6	15.4	17.1
Low limit (-25%)	0.5	1.6	5.2	9.2	10.3

These data are abstracted from Exhibit 3

Exhibit 1a

AIR EFFLUENT QUALITY CONTROL UNIT COSTS

A. Facilities Operated by Hypothetical Firms before Installing New Environmental Facilities

Firm	A	B	C
Number of Refineries	10	1	1
Total Firm crude distilling capacity, barrels per stream day	277,000	53,000	25,000
Number of catalytic cracking units	10	1	1
Capacity of each catalytic cracking unit, barrels per stream day	10,000	10,000	10,000
Number of carbon monoxide boilers and electrical precipitators	6	0	0
Number of sulfur recovery plants	4	0	0
Number of sulfur plant off-gas scrubbers	0	0	0
Number of crude storage tanks without floating roofs	40	3	12
Number of gasoline storage tanks without floating roofs	441	20	20

These data are abstracted (or implied) from Exhibit 3

Exhibit 1b

AIR EFFLUENT QUALITY CONTROL UNIT COSTS

B. Air Quality Control Facilities Required to be Installed by Hypothetical Firms

	A		B		C	
	No. of Units	Capital Cost Million $	No. of Units	Capital Cost Million $	No. of Units	Cap.Cost Million $
Electrical precipitators	4	2.26	1	0.56	1	0.20
Carbon monoxide boilers	4	7.20	1	1.50	1	0.47
Sulfur recovery plants	12	7.50	2	0.96	2	0.95
Sulfur plant off-gas scrubbers	12	5.70	2	0.86	2	
Crude tank floating roofs	40	2.12	2	0.10	12	0.79
Gasoline tank floating roofs	111	7.10	28	0.45	20	
Total Capital Cost		31.94		4.43		2.41
Total Operating & Maintenance Costs, Million $ per year		0.78		0.14		0.08

These costs, abstracted from Exhibit 3, are therein stated to have an uncertainty bounded by +100% and -50%

Exhibit 2.

WATER EFFLUENT QUALITY CONTROL TOTAL COSTS

Total Industry Capital Investments Required
Million $

	1972	1973	1974	1975	1976	Total
To control emissions from existing facilities	52.7	53.8	55.0	56.1	57.2	274.8
To include control equipment in newly built facilities	1.6	1.6	1.6	1.6	1.6	8.0
Total	54.3	55.4	56.6	57.7	58.8	282.8
Estimated Range						
High limit (+60%)	86.9	88.6	90.6	92.3	94.1	452.5
Low limit (-25%)	40.7	41.6	42.4	43.3	44.1	212.1

Annual Costs to Operate and Maintain Control Equipment
Million $

	1972	1973	1974	1975	1976
Expected Cost	1.4	2.9	4.4	5.8	7.2
Estimated Range					
High limit (+60%)	2.2	4.6	7.0	9.3	11.5
Low limit (-25%)	1.0	2.2	3.3	4.4	5.4

These data are abstracted from Exhibit 4

Exhibit 2a

WATER EFFLUENT QUALITY CONTROL UNIT COSTS

	A	B	C
Volume of effluent water to be treated, million gallons per day	0.066	0.66	6.6
Capital cost to install effluent treatment plant, $ million	0.25	0.93	4.66
Cost to operate and maintain plant, $ million per year	0.01	0.09	0.60

These costs, abstracted from Exhibit 4, are therein stated to have an uncertainty bounded by +150% and -75%

AIR POLLUTION

ABATEMENT CONTROL COSTS

PETROLEUM REFINING

The processes identified as sources of air pollutants in petroleum refining operations are storage tanks, hydrogen sulfide combustion, and catalyst regeneration. The methodology for arriving at a national cost estimate is outlined below.

Control costs for storage tanks were estimated using a model tank approach. The method of control is to convert from fixed roof to floating roof tanks. Gasoline tank costs were estimated using a distribution of tanks by size and number. A unit cost per size was multiplied by the number of plants in each size. The resultant estimate was multiplied by 1/4 to reflect the assumption that 75% of such tanks are currently controlled. Crude storage estimates were prepared using a model tank of 80,000 B capacity. The unit cost was projected to the national figure and again the total investment multiplied by 1/4. Annual costs were assumed to be offset by a credit from recovered materials.

Sulfur oxides are expected to be controlled using sulfur recovery plants and tailgas scrubbing. Refineries with existing plants were known and costs were estimated for adding sulfur plants to the remainder. Parallel sulfur plants were included with a total capacity equal to twice the production level. Scrubbers were added to the exhaust gasses of all sulfur plants.

Control costs were estimated for only fluid catalytic cracking units greater than 10,000 B/D. All other catalytic cracking units were assumed to meet the standards. Each FCC unit was costed separately and the national cost is simply the summation of these costs. Precipitators were used to control particulates and CO boilers for carbon monoxide. The cost for CO boilers was adjusted to reflect that not all the costs can be attributed to air pollution control since some process

benefits are derived from their installation. Fifty percent of the investment cost for CO boilers was attributed to air pollution control. Ten percent of this investment cost was included for the annual cost.

As indicated on page 3, these estimates do not include costs associated with the production of unleaded gasoline or desulfurized fuels. While these activities will create demands for capitol (2 to 4 billion for unleaded gasoline and about 2 billion for low sulfur fuels), they will be revenue producing operations for the refineries and have not been considered abatement costs herein.

These estimates have been developed as indicated above and may not necessarily be the same as those contained in the 1972 report to Congress entitled "The Economics of Clean Air," due to differences in basic assumptions.

COSTS AND RELATED ASSUMPTIONS FOR THE Petroleum Refining INDUSTRY

TOTAL COSTS ($millions - August, 1971=100)

Investment 1/

	1972	1973	1974	1975	1976
—Cost to control existing facilities	22.9	45.7	160.	182.8	45.7
—Costs to control new facilities	21.	21.	21.	21.	21.
—TOTAL	43.9	66.7	181.0	203.8	66.7

Annual 2/

—Operation and Maintenance	.7	2.1	6.9	12.3	13.7
—Interest	2.8	8.4	28.1	50.5	55.2
—Depreciation	2.8	8.4	28.1	50.5	55.2
—TOTAL	6.3	18.9	63.1	113.3	124.1

Total 3/

—Total Cash	47.4	77.2	210.0	266.6	136.6
—Total Direct	44.0	58.8	187.9	215.1	80.4

Uncertainty

Figures above are EPA's estimates of highest possible costs associated with assumptions outlined below, and EPA expects the real costs to be lower. However, other credible sources estimated the costs could be higher. Accordingly, a reasonable range is from - 25 % to + 25 %.

The figures could reasonably be -25% lower because:

1. There could be more control in place than was assumed in these estimates.

2. Technology could improve thus the unit costs could be lower.

3. Sulfur plants were costed for capacity of 200% of estimated production (two parallel plants). Less capacity may in fact be installed.

The figures could reasonably be 25 % higher because:

1. Additional pollutants (NO_x, odors) may require control and thus increase the costs at some time in the future.
2. Additional point sources like fuel transfer points may require control in the future.
3. Additional costs may be encountered if serious problems are encountered in SO_x control.

UNIT COSTS ($millions - August, 1971=100)

	Type of Plant 1/				
	A	B	C	D	E
Investment					
--Cost to control existing facility	31.9	4.45	2.41	____	____
--Cost to control new facility	____	____	____	____	____
—Total	____	____	____	____	____
Annual					
—Operations and maintenance	.78	.139	____	____	____
—Interest	2.06	.274	____	____	____
—Depreciation	2.06	.274	____	____	____
—Total	4.90	.687	.396	____	____
Total					
--Total Cash	34.74	4.863	____	____	____
—Total Direct	32.68	4.589	____	____	____
Uncertainty					
—Upper bound	+100%	____	____	____	____
--Lower bound	-50%	____	____	____	____

The figures could reasonably be higher because:

1. Site conditions at some refineries may make the cost of installation control facilities more expensive.
2. Regional variations in construction costs.
3. Added problems may be encountered in SO_x control.

The figures could reasonably be lower because:

1. New SO_x control technology may be developed which is lower in cost than the control systems estimated herein.
2. Some facilities may already include some of the required control facilities.

ASSUMPTIONS

1. Standard

a. Particulates - Process Weight regulation that appears in the Federal Register on pages 15495 and 15496.

b. Hydrocarbons - All stationary tanks, reservoirs, and containers with more than 40,000 gallon capacity and a vapor pressure of 1.5 psia (or greater) must be equipped with floating roofs, vapor recovery systems other equally efficient devices. In addition, submerged filling inlets must be installed on all gasoline storage tanks with a capacity of 250 gallons or more.

c. Sulfur oxides - process standard of 500 ppm

d. Carbon Monoxide - complete combustion.

2. Current level of control

a. Relative to industry costs

(1) Storage tanks: 75% of the tanks are currently controlled to achieve the standard (100% of Cal. controlled)

(2) Refinery:

SO_2 - 37% control

Particulates - 67% for the catalyst regenerator

Carbon monoxide - 47%

b. Relative to unit costs

All unit costs reflected new cost for precipitators, CO boilers, sulfur recovery plants and conversion costs for storage tanks.

3. Abatement technology (by type of plant)

a. All storage tanks requiring control were converted to floating roof. Submerged filling costs were minimal. No operating and maintenance costs considered because of HC recovery.

b. Catalyst regenerators:

Used CO boilers for carbon monoxide.

c. Sulfur oxides:

Used sulfur recovery plants plus tailgas scrubbing.

4. Interest Rate: 10%

5. Growth Rate: 2.7%/year in both production and capacity.

6. Depreciation Rate: 10%/year

7. Down-time: None

8. Phasing:

The costs associated with air standards are derived from the Cost of Clean Air figures which are computed as total cumulative investment required by 1976 and as annual costs in 1976. Accordingly, the investment costs to bring existing facilities up to standards are phased over the five years -- 5%, 10%, 35%, 40%, 10% and the investment costs of controlling new facilities (growth) are assumed to be linear. The total annual costs are phased -- 5%, 15%, 50%, 90%, 100%.

The costs associated with water standards are phased on the straight line basis from 1971 to 1976.

FOOTNOTES 47

Exhibit 3.
Pg. 8

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1/ These costs include the direct incremental investment required to attain environmental standards (i.e., for investment required to attain standards in addition to investment that had already been made prior to and during 1971). These costs include control equipment, auxiliary equipment, buildings, land, and down-time (i.e., the opportunity costs associated with stopping production to install, modify, or replace pollution abatement equipment). The investment costs to control existing facilities include all those costs required to enable existing facilities to attain (and continue to attain) environmental standards while maintaining the 1971 level of production. The investment costs to control new facilities include the additional investment required to attain environmental standards over and above what the cost of the facility would have been without the standards.

The costs to control existing facilities may be overstated for two reasons. First, a firm may choose to build a new facility rather than modify an old one. Second, a firm may choose to curtail production rather than absorb the costs required to maintain production. Accordingly, the costs reported above may err on the high side since a firm presumably would not build a new plant or curtail production if it were not the least expensive alternative.

2/ These costs include the incremental operating expenses (i.e., for expenses required to attain and maintain standards in addition to expenses already being incurred during base year) associated with attaining and maintaining environmental standards net of any productivity increases or by-product revenues associated with pollution abatement investments.

3/ Total cash costs equal investment costs plus annual costs minus depreciation. Total direct costs equals total cash costs minus interest.

4/ Configuration:

Equipment	Plant A No.	Plant A Inv. $ x 10^6	Plant A Ann. $ x 10^6	Plant B No.	Plant B Inv. $ x 10^6	Plant B Ann. $ x 10^6
CO Boiler	4	7.2	.72	1	1.5	0.15
Sulfur Plant	12	7.56	-	2	0.96	-
Scrubbers	16	5.7	1.6	2	0.864	0.242
Predipitators	4	2.26	.731	1	0.565	0.183
Crude Storage	40	2.12	.425	3	0.105	0.21
Gasoline Storage	441	7.1	1.420	28	0.453	0.91

Plant A reflect a large fully integrated national producer (10 refineries), 677,000 Bbl/CD and Plant B, a small independent partially integrated firm (1 refinery), 53,000 Bbl/CD.

(See next sheet for Type C Plant Unit Costs.)

TYPE C PLANTS	25,000 bbl small refineries.	
Unit	Inv.	Total Ann.
	$x10^3$	$x10^3$
Cat-Cracker	10,000 bbl capacity	
particulates	200	66
CO boiler (1/2 cost)	470	47
sulfur plant and tailgas scrubbing	953	126
Storage Tanks		
12 crude (50,000 bbl)		
20 gasoline (15,000 bbl)	788	158
	2,411	396

Water Pollution Abatement Costs

Exhibit 4.

Petroleum

The costs reported in this document were calculated using a computer-based model developed to estimate the total costs (capital and operating) required by the nation's industries to attain water pollution control standards. The output of this model has been and will be published in EPA's report to Congress - Economics of Clean Water. However, the costs reported herein will not necessarily be the same as those in the 1972 Economics of Clean Water because some of the underlying assumptions may differ slightly.

The methodology built into the model to estimate both the total costs for the industry and the unit costs for individual establishments is discussed below.

Total Costs

Total costs were estimated by aggregating individual capital and operating cost figures for each establishment in the industry using over 10 million gallons per year. The methodology employed can be summarized in fourteen steps:

1. Identify establishments. The first step was to identify those establishments that discharge significant quantities of water (i.e., over 10 million gallons per year); 14,526 establishments were identified from the Census of Manufactures, 1963 and 1967.

2. Segment establishments. The next step was to segment these establishments into groups with similar waste-water characteristics; 71 industrial subgroups were identified by SIC code.

3. Develop standardized treatment procedures. For each of the 71 subgroups standardized treatment procedures were developed based primarily on a review of the technical literature; the procedures that were developed, because they can be applied to all establishments, are likely to be high-cost procedures for individual establishments.

4. Describe each establishment in terms of size and location. Since both size and geographic location have a significant impact on water pollution costs, each of the establishments were described in terms of employment and location using the Dun and Bradstreet files.

5. Estimate waste-water discharge per establishment. Having identified the size and location characteristics of the establishments, waste-water discharge was estimated as a function of both size and location. (This procedure estimated a total industry-wide waste-flow that was 93.2% of that reported by the Census Bureau.)

6. Assign a percentage of waste-water discharge to each of the pollution-abatement processes (identified in 3 above). Then, based on a survey of the technical literature, the portion of the waste-water discharge that would be treated by various pollution-abatement processes was assigned.

7. Scale waste-water discharges. Since the strength of the waste of the various industry subgroups varies, scaling factors derived from a review of the technical literature were multiplied times each volume of waste-water discharge to account for these variations (see Table I).

8. Determine pollution-abatement investment required to attain environmental standards. Using the cost-estimating equations described in the following section, the total investment for each industry was estimated; to get the incremental investment required as of the base year, the model was run as a function first of total industry waste-water discharge and second of industry waste-water discharge being treated as of the base year (based on Census of Manufacturers data), and the difference was taken.

9. Compute annual investment. Then annual investment required to bring existing facilities up to standards is scheduled in equal increments from base year to 1976 so that all required investment is made by 1976.

10. Compute growth investment. [illegible] (i.e., pollution-abatement investment required to bring new facilities up to standard). Growth investment is computed as a function of the size of the industry (measured by total investment requirements) where the historical growth rate of the industry is modified by the change in water productivity (the amount of water required to produce a given output).

11. Compute replacement investment. Required replacement investment is computed as a function of capitalization in the previous year where the replacement rate equals the depreciation rate.

12. Compute capitalization (i.e., pollution-abatement investment already made). Then, capitalization in a year is computed as a function of what it was in the previous year plus annual investment plus growth investment plus replacement investment minus depreciation (where for the purposes of the model replacement investment equals depreciation).

13. Compute interest. Interest is computed as a funtion of capitalization where it is assumed that all investments are debt-financed.

14. Compute operations and maintenance costs. These are computed as a function of waste-flow (as were the total investment requirements) using the estimating equations outlined below.

Unit Costs

The costs for individual establishments were computed using cost-estimating equations which expressed costs as a function of the flow of waste-water discharge:

$$\text{Log (cost)} = A + B \log (\text{flow}) + C (\log (\text{flow}))^2$$

Such equations have been developed for eleven different pollution-abatement processes where the parameters were set using regression analysis. Accordingly, after a configuration of processes has been developed for an industry, the costs can be estimated for any establishment in that industry given the waste-water discharge of that establishment. These equations and related parameters are listed in Table II.

TABLE I

SCALING FACTORS*

Bakeries	1
Cement	1
Electric Utilities	1
Iron Foundries	1
Fruits and Vegetables	2
Leather	4
Primary Non-ferrous	1
Petroleum	2
Pulp and Paper - pulp	6
Paper	3
Steel	1

* - In scaling the flows for individual industries the scaling factors are used as a simple multiplier - but to the 0.6 power to account for economies of scale.

Last Twice. Last time

TABLE II

COST ESTIMATING MODEL

GENERAL EQUATION: Log (Cost) = A + Log (Flow) [B+C Log (Flow)]

				TERMS			$1967 Per Million Gallons/Day		
				A	B	C	0.1	1.0	10.0
01010	21	CC	OIL SEPARATION	4.7470	0.2264	0.2219	10976.01	55840.59	780514.33
01020	22	OM	OIL SEPARATION	0.6435	-0.1767	0.0	2513.28	15300.01	102010.67
01030	31	CC	EQUALIZATION	4.6233	0.7455	-0.2236	7520.01	42000.67	234000.41
01040	32	OM	EQUALIZATION	-0.3010	-0.5102	0.0005	600.17	1700.00	6000.00
01050	41	CC	COAGULATION-SEDIMENTATION	5.5240	0.6134	0.0884	82035.16	334002.75	1412237.02
01060	42	OM	COAGULATION-SEDIMENTATION	0.6602	-0.2176	0.0850	3441.10	25000.00	210000.35
01070	51	CC	NEUTRALIZATION	4.6990	0.8556	-0.2272	5100.57	50000.00	473000.24
01080	52	OM	NEUTRALIZATION	0.2430	-0.1008	0.0	772.57	6125.03	48550.03
01090	61	CC	FILTRATION	4.5011	0.1414	-0.0357	26100.46	38000.50	540010.73
01100	62	OM	FILTRATION	0.6435	-0.1767	0.0	2513.28	15300.01	102010.67
01110	71	CC	SEDIMENTATION	5.4803	0.0557	0.0	78024.17	282410.47	1012511.44
01120	72	OM	SEDIMENTATION	0.6435	-0.1767	0.0	2513.24	15300.01	102010.67
01130	81	CC	AERATION	4.5441	0.2341	0.0	20410.01	35000.10	60000.03
01140	82	OM	AERATION	-0.3010	-0.5102	0.0005	600.17	1700.00	6000.00
01150	11	CC	Clarification	5.2750	0.6020	0.0	27073.85	110000.04	523000.20
01160	12	OM	Clarification	0.8003	-0.3006	0.0788	1200.05	4300.55	22000.72
01170	91	CC	EVAPORATION	4.1761	0.7032	0.0	3257.77	14000.06	60000.32
01180	92	OM	EVAPORATION	0.2430	-0.1008	0.0	772.57	6125.03	48550.03
01190	101	CC	CRYSTALLIZATION	6.1123	1.0000	0.0	1290400.07	1290000.75	1290000.55
01200	102	OM	CRYSTALLIZATION	-0.0711	-0.2431	0.0	520.10	2071.31	10074.03
01210	111	CC	INCINERATION 4/	6.0566	0.0344	0.0	2100203.50 1/	9040821.672/	38000833.06 3/
01220	112	OM	INCINERATION 4/	1.5703	-0.3721	0.0	31025.50	132000.00	564074.03

* C= Capital Cost
** OM= Operating and Maintenance Costs

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1/ Approximately $200,000 a year of materials recoverable, exclusive of net heat values

2/ Approximately $1,000,000 a year of materials recoverable, exclusive of net heat values

3/ Approximately $4,000,000 a year of materials recoverable, exclusive of net heat values

4/ All incineration numbers are too high by a factor of 13.

53

Exhibit 4.
Pr. 5

PETROLEUM REFINING

Exhibit 4.
Pg. 5

COSTS AND RELATED ASSUMPTIONS FOR THE SIC 2911 INDUSTRY

TOTAL COSTS ($millions - August, 1971=100)

Investment 1/

	1972	1973	1974	1975	1976
—Cost to control existing facilities	52.66	53.80	54.95	56.10	57.25
—Costs to control new facilities	1.56	1.56	1.57	1.57	1.58
—TOTAL	54.22	55.36	56.52	57.67	58.83

Annual 2/

—Operation and Maintenance	1.43	2.87	4.36	5.75	7.18
—Interest	2.52	5.09	7.57	10.09	12.61
—Depreciation	1.26	2.52	3.78	5.04	6.30
—TOTAL	5.20	10.43	15.66	20.88	26.09

Total 3/

—Total Cash	58.16	63.27	68.10	73.51	78.62
—Total Direct	55.64	58.18	60.83	63.12	66.01

Uncertainty

Figures above are EPA's estimates of highest possible costs associated with assumptions outlined below, and EPA expects the real costs to be lower. However, other credible sources estimated the costs could be higher. Accordingly, a reasonable range is from - 25 % to + 60 %.

The figures could reasonably be 25 % lower because:

a. Treatment configurations of equal effectiveness and lower costs are available to industry (15%).

b. Improved hydraulic engineering could accelerate water productivity and cause substantial reduction in treatment costs (10%)

Exhibit 4.
Pr. 7

The figures could reasonably be 60 % higher because:

a. Current level of control could be about 70% instead of 80% because previously installed facilities could be qualitatively inferior to those being installed today (20%)

b. Some localities may set standards that require additional treatment like activated charcoal (20%)

c. Ballast water from tankers, which will require treatment, was not included in the estimates (10%)

d. Thermal pollution standards would require cooling towers (10%)

UNIT COSTS ($millions - August, 1971=100)

	Type of Plant 4/				
	A	B	C		
Investment					
--Cost to control existing facility	.248	.928	4.659		
--Cost to control new facility	.248	.928	4.659		
--Total	.248	.928	4.659		
Annual					
--Operations and maintenance	.014	.090	.604		
--Interest	.025	.093	.466		
--Depreciation	.012	.046.	.233		
--Total	.051	.229	1.303		
Total					
--Total Cash	.287	1.111	5.729		
--Total Direct	.262	1.018	5.263		
Uncertainty					
--Upper bound	+150	+150	+150	+150	+150
--Lower bound	-75%	-75%	-75%	-75%	-75%

The figures could reasonably be higher because:

a) Higher construction costs

Northeast	23%
Great Lakes	18%
Northern Plains	11%

b) Obsolete processes and hydraulic engineering (100%)

c) Lack of space for cost-effective treatment measures (100%)

d) If additional treatment like activated charcoal is required, costs could go up (20%)

e) Thermal standards would require cooling towers (10%)

f) Treatment of ballast water from tankers (10%)

The figures could reasonably be lower because:

a) Treatment configurations of lower costs but equal effectiveness are available (50%)

b) Lower regional construction costs

Pacific Coast	32%
Southwest	29%
Southern Plains	31%
Southeast	18%

c) Improved hydraulic engineering could accelerate water productivity and cause rapid reduction in treatment costs (50%)

ASSUMPTIONS

1. Standard

Highest available applicable conventional technology (see assumption

2. Current level of control

a. Relative to industry costs

Industry pollution-abatement facilities have a current replacement value of $498 million as compared to a total requirement of 646 million (in August, 1971 dollars).

b. Relative to unit costs

Zero

3. Abatement technology (by type of plant)

Method	% of process waste-flow
oil separation	100
equalization	20
coagulation	40
neutralization	20
flotation	80
sedimentation	60
stabilization	130

4. Interest Rate: 10%

5. Growth Rate: 2.7 increase in production modified by 2.5% increase in water productivity

6. Depreciation Rate: 5%/year

7. Down-time: installation multiple = 1.35

8. Phasing:

The costs associated with air standards are derived from the Cost of Clean Air figures which are computed as total cumulative investment required by 1976 and as annual costs in 1976. Accordingly, the investment costs are phased over the five years -- 5%, 10%, 35%, 40%, 10% -- and the annual costs are phased -- 5%, 15%, 50%, 90%, 100%.

The costs associated with water standards are phased on the straight line basis from 1971 to 1976.

FOOTNOTES

1/ These costs include the direct incremental investment required to attain environmental standards (i.e., for investment required to attain standards in addition to investment that had already been made prior to and during 1971). These costs include control equipment, auxiliary equipment, buildings, land, and down-time (i.e., the opportunity costs associated with stopping production to install, modify, or replace pollution abatement equipment). The investment costs to control existing facilities include all those costs required to enable existing facilities to attain (and continue to attain) environmental standards while maintaining the 1971 level of production. The investment costs to control new facilities include the additional investment required to attain environmental standards over and above what the cost of the facility would have been without the standards.

The costs to control existing facilities may be overstated for two reasons. First, a firm may choose to build a new facility rather than modify an old one. Second, a firm may choose to curtail production rather than absorb the costs required to maintain production. Accordingly, the costs reported above may err on the high side since a firm presumably would not build a new plant or curtail production if it were not the least expensive alternative.

2/ These costs include the incremental operating expenses (i.e., for expenses required to attain and maintain standards in addition to expenses already being incurred during base year) associated with attaining and maintaining environmental standards net of any productivity increases or by-product revenues associated with pollution abatement investments.

3/ Total cash costs equal investment costs plus annual costs minus depreciation. Total direct costs equals total cash costs minus interest.

4/ All costs are primarily a function of the volume of waste-water

Type	Waste-water Discharge (mgd)
A	0.1
B	1.0
C	10.0